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Simultaneous co-integration of multiple electrical storage applications in a consumer setting

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A B S T R A C T

In a consumer setting, storage systems can be dispatched in order to shift surplus generation to periods when a local generation deficit exists. However, the high investment cost still makes the deployment of storage unattractive. As a way to overcome this problem existing literature looking at storage installed at the grid-level suggests dispatching the storage device for multiple applications simultaneously in order to access several value streams. Therefore, in this work, a Mixed Integer Linear Program is developed in order to schedule the operation of a storage device in a consumer context for multiple objectives in parallel. Besides shifting locally generated energy in time, the peak demand seen by the electric grid is reduced and the storage device is operated to provide primary reserve control. The model is applied in a case study based on the current German situation in order to illustrate the value contribution of stacking multiple services. When pursuing multiple applications simultaneously, the revenues of storage can be increased significantly. However, the revenues are not additive due to conflicting operations which originates a revenue gap as illustrated in the paper.

1. - Introduction

In Germany, electricity tariffs for residential consumers have increased by more than 20% over the last five years, driven by taxes and surcharges which account for more than 50% of today's retail price [1]. As a consequence, the local generation of electricity by photovoltaic (PV) systems and cogeneration units (CHP) for immediate self-consumption are becoming more popular. Especially for PV systems, this development was also supported by decreasing investment cost. However, at the same time, feed-in tariffs have also declined significantly. Therefore, over time, the objective of many adopters of distributed generation technologies has also shifted. Whereas initially the goal was to maximize feed-in in order to generate additional income, today the focus for the deployment of distributed generation resources usually is the substitution of the energy taken from the grid by locally generated energy in order to reduce the electricity bill.

In this context and depending on the installed capacity of a PV system, Weniger et al. [2] found that residential consumers can achieve a self-sufficiency of about 30% without a storage system. This is in line with Castillo-Cagigal et al. [3], who identified a share of 32.7% of energy that can immediately be supplied by PV generation. In their literature review, Luthander et al. [4] report that typically 15–50% of locally generated energy from a PV system can be self-consumed. This share can be further increased by demand-side management (DSM), which schedules flexible loads to periods of generation surplus. While initial increases in self-sufficiency can oftentimes be achieved without much efforts, further gains are usually associated with a reduction of comfort. By deferring flexible loads such as running the washing machine, Castillo-Cagigal et al. [3] identified additional gains of up to 25%, increasing the self-sufficiency to about 57%.

While these numbers refer to intermittent photovoltaic generation, even for dispatchable CHP units the alignment of electric generation to demand faces several hurdles such as the variability of electric demand or restrictions from the associated heat process. Barbieri et al. [5] found that less than 85% of local electric demand can be satisfied by a cogeneration unit while Hawkes and Leach [6] report a range from 62% to 87%. Ren and Gao [7] determined a significantly lower level (24%), but they assumed a system with a very small capacity in their analysis.

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In order to further increase the share of self-consumed generation, small scale storage systems such as batteries installed at the consumer site have seen a recent rise in interest and publicity. These are commonly installed to shift energy in time. Time shifting (TS) refers to transferring energy in time to align the generation and the demand profiles. Under this application, the storage device absorbs surplus energy, when local generation exceeds load. At a later time, when electrical load exceeds generation, the deficit is then supplied by the storage device to satisfy demand, as long as there is stored energy. In this context, storage can be beneficial if the feed-in tariff is below the consumption tariff. Weniger et al. [2] found that by installing a storage device in a single-family house already equipped with a photovoltaic (PV) system, the self-sufficiency can be increased from about 30% to about 60%. Castillo-Cagigal et al. [3] even identified an increase to slightly above 70%, without compromising the comfort that could be reduced due the adoption of demand-side management. Mulder et al. [8] concluded that storage deployed for time-shifting breaks-even under current cost and is attractive when expecting rising electricity tariffs.

Alternatively, storage can also be beneficial when no local generation resource exists but the consumer has access to a time of use or dynamic tariff with a sufficient price spread. Dufo-López and Bernal-Agustín [9] dispatch a storage device to benefit from a time of use tariff in their application. In this case, the storage device is charged when the electricity tariff incentivizes consumption. Later, when a more expensive rate applies, demand is satisfied by discharging the storage device. However, the authors found that the savings under such a tariff scheme are not sufficient to justify a storage investment. This view is confirmed by Carpinelli et al. in Refs. [10] and [11], who considered the application for residential and industrial use cases. They found that the installation cost is still too high and the electricity tariffs do not provide sufficient incentives. However, besides installing a storage system for shifting energy in time, additional applications with an immediate commercial benefit exist. While the objective of time shifting is to reduce energy cost, peak shaving (PS) aims at reducing power related fees. These are typically charged based on the highest demand within each billing period. The objective is therefore to reduce the peak demand and hence the required grid capacity as far as possible. In their analysis, Purvins et al. [12] were able to reduce peak demand up to 44% by dispatching a storage device. However, they caution that benefits decrease with the scale of the deployed storage system. Zheng et al. [13] found that a typical U.S. consumer can reduce the annual cost by up to 39%, depending on the chosen technology and the chosen tariff. Johnson et al. [14] caution that the evaluation of peak shaving is sensitive to modelling errors, as one optimizes for the maximum of a variable and not the sum. The same thread also affects a potential implementation in reality, as an erroneous storage dispatch in one period can eliminate or at least compromise the complete benefits.

While TS and PS reduce the electricity bill, the provision of ancillary service by storage presents an additional income source. Ancillary services are usually contracted by System Operators in order to support and ensure the stable operation of the grid. Walawalkar et al. [15] analyse several US markets and find that the deployment of storage for such a service is attractive. Steffen [16] concludes for the German market that the provision of ancillary service is also profitable. However, this attractiveness differs due to widely diverging local regulations. Due to their ability to both absorb and provide power as well as the short reaction times, most battery storage technologies are well suited to provide primary reserve control (PRC). However, it has to be considered that these devices are energy limited. Despite its financial attractiveness, Nailis et al. [17] alert that the entrance of additional market agents could easily exceed the limited demand for such services and therefore reduce the associated compensation.

One of the main barriers that still prevents a more widespread usage of storage in a distributed context is the investment cost. However, storage dispatched for only one application is oftentimes underutilized and spends a significant amount of time in an idle state. Sioshansi et al. [18] find that a storage dispatch considering only an individual service therefore “is likely to significantly underestimate the value and social benefits of energy storage”. Xi et al. [19] consider the dispatch of storage for multiple services “critically important”. By accessing several value streams in parallel, the break-even threshold of a storage system can then be lowered. However, the co-integration of multiple applications is not trivial. Usually, the applications cannot simply be stacked, but their interaction and mutual impact on power and energy capacity must be carefully considered to extract the full value potential. The dispatch process must ensure that operational limits are not exceeded at any time. Furthermore, requirements from regulatory and contractual obligations have to be satisfied at all times to avoid penalties or the exclusion from market access [20]. The resulting restrictions in the dispatch will frequently require trade-offs, which lead to sub-additive results [19].

The simultaneous provision of multiple services has been analyzed by several authors. Kazempour et al. [21,22], He et al. [23], Drury et al. [24] and Goebel and Jacobsen [25] dispatch a storage device simultaneously to benefit from temporal price differences (‘arbitrage’) as well as to provide reserve control. Kazempour et al. develop a Mixed Integer Non-Linear Program [21] and a Mixed Integer Program [22] to model this problem. They find that the provision of reserve control is responsible for the majority of revenues. He et al. [23] developed their analysis regarding the French market and concluded that aggregating services can bring storage to the break-even point. Drury et al. [24] reach the same conclusion looking at several U.S. markets. The results from Goebel and Jacobsen [25] indicate that the conclusions from the previous authors, who looked at large central storage systems, are also valid for small-scale, distributed storage systems.

All publications agree that stacking applications improves the value proposition of storage. While [21–25] highlight the feasibility and benefit of combining arbitrage and ancillary services, there is little literature looking at the combination of further storage applications. Zucker et al. [26] for example dispatch a storage device for arbitrage operations and also for time shifting of PV generated electricity as a way to significantly enhance its profitability. Xi et al. [19] furthermore integrate the provision of backup power in case of a grid failure.

In a consumer context, storage was found to reduce energy cost by shifting excess generation from local generation resources in time to periods with insufficient local generation. However, in most cases the investment cost is still too high to justify an investment in storage. Previous research – focusing on the application of storage on the grid-level – showed that aggregating two or more applications can increase revenues. Having in mind the previous literature review, in this work an operation procedure process is designed to dispatch a storage device simultaneously for three applications in a residential context with local generation. Time shifting of energy, peak shaving as well as the provision of primary reserve control will be considered in order to capture multiple value streams in parallel. This will allow determining if such a simultaneous dispatch is feasible from an operational perspective as well as to analyse the resulting revenues.

Besides photovoltaic systems, the process will also consider cogeneration units. In order to fully integrate them, their heat output must be considered as well. Therefore, besides the electrical

Table 1
System parameters.

$E_{Storage}^{Capacity}$	[Wh]	Nominal capacity of the storage device
P_{System}^{max}, $\dot{Q}_{System}^{max}$	[W]	Maximum power and heat flow
$P_{PV}^{max\ \ feed-in}$	[W]	Maximum permissible feed-in power of a PV installation
P_{CHP}^{min}	[W]	Minimum power output of a cogeneration unit
$\delta_{ElStorage}$	[%]	Depth of discharge of the storage device
$\eta_{ElStorage}^{In}$, $\eta_{ElStorage}^{Out}$	[%]	Charging/discharging efficiency of the storage device
$\phi_{ElStorage}$	[%]	Self-discharge per hour of the storage device
$C_{System}^{Variable}$	[€/Wh]	Operating cost
$C_{Grid}^{Capacity}$	[€/W]	Demand charge
$R_{Grid}^{Import}(t)$	[€/Wh]	Electricity tariff
$R_{PV}^{Export}(t)$, $R_{CHP}^{Export}(t)$	[€/Wh]	Feed-in tariffs
$R^{Regulation}(t)$	[€/W]	Compensation for the provision of PRC

Table 2
Simulation variables.

$E_{Storage}(t)$	[Wh]	Current charge of the storage device
$Q(t)$	[W]	Heat flow
$\dot{Q}_{ThStorage}(t)$	[W]	Heat flow absorbed/supplied by the thermal storage device
$P(t)$	[W]	Power
$P_{Grid}^{Import}(t)$, $P_{Grid}^{Export\ \ PV}(t)$, $P_{Grid}^{Export\ \ CHP}(t)$	[W]	Power exchange with the grid
$P_{PV}^{*}(t)$	[W]	Available PV generation
$P_{ElStorage}^{In}(t)$, $P_{ElStorage}^{Out}(t)$	[W]	Power absorbed/supplied by the electric storage device
$P_{Regulation}^{Capacity}(t)$	[W]	Tendered capacity for the provision of reserve control
$P_{Grid}^{Capacity}(t)$	[W]	Grid connection capacity
$y(t)$	–	Binary decision variable for the operation of the storage device
$z(t)$	–	Binary decision variable for the operation of the cogeneration unit

system, the model will also take the thermal system into account.

2. - Methodology

To determine the optimum dispatch of the storage device as well as the entire system components, a Mixed Integer Linear Program (MILP) will be developed. It describes an optimization problem, which is constrained by linear relationships representing the functionality of the system. In addition, some of the variables can only assume integer values.

The optimization horizon is defined by T, where the index t refers to each time step. The duration of each time step is Δt, expressed as a fraction of an hour. Power will be denoted $P(t)$ and heat flows $Q(t)$, where positive values represent energy provided and negative values energy absorbed by the specified system. Energy flows are assumed to be constant during each period t. Table 1 provides an overview of the system parameters, where subscripts indicate the affected subsystem and superscripts differentiate between further properties. The subscript *Load* indicates the local demand, *ElStorage* refers to an electric storage and *ThStorage* to a thermal storage device. The simulation variables considered in the MILP are enumerated and described in Table 2.

Fig. 1 shows a simplified representation of power and heat flows.

In addition, the following assumptions were admitted for the formulation of the MILP problem:

- Self-discharge ϕ is considered only for thermal storage, as the most commonly used Lithium-Ion batteries have neglectable self-discharge, when energy is shifted over relatively short time periods.
- Efficiency losses from storage operations are only considered for the electric storage, as the heat exchanger of the thermal storage system is assumed to be 100% efficient. This results in a requirement to split $P_{ElStorage}(t)$ into two separate vectors, indicating charging ($P_{ElStorage}^{In}(t)$) and discharging ($P_{ElStorage}^{Out}(t)$) power.
- Power exchange with the grid is split into separate vectors for energy taken from the grid ($P_{Grid}^{Import}(t)$) and energy fed into the grid ($P_{Grid}^{Export\ \ PV}(t)$ and $P_{Grid}^{Export\ \ CHP}(t)$) to differentiate between different consumption and feed-in tariffs.
- $R_{Grid}^{Import}(t)$ is assumed to be greater than $R_{PV}^{Export}(t)/R_{CHP}^{Export}(t)$ to avoid simultaneous import and feed-in of energy.

2.1. Time-shifting (TS)

Given a certain system configuration, the objective is the maximization of the gross margin, that is the revenues minus the cost, as indicated by Equation (1). Revenues are derived from the feed-in of energy from both the PV and the CHP systems. Contrary, costs are related to the electricity taken from the grid as well as the operating cost of the cogeneration unit and the gas burner (GB), which is dispatched to meet peak demand for heat.

$$\max \Delta t \times \sum_{t=1}^{T} \left(\begin{array}{l} -P_{Grid}^{Import}(t) \times R_{Grid}^{Import}(t) - \dot{Q}_{GB}(t) \times C_{GB}^{Variable} - \left(P_{CHP}(t) + \dot{Q}_{CHP}(t)\right) \times C_{CHP}^{Variable} \ldots \\ -P_{Grid}^{Export\ \ PV}(t) \times R_{PV}^{Export}(t) - P_{Grid}^{Export\ \ CHP}(t) \times R_{CHP}^{Export}(t) \end{array} \right) \quad (1)$$

The dispatch of the system is subject to a wide range of constraints to ensure the operation within technical limits as well as the continuous balance of supply and demand. First, the electric system will be discussed, followed by the thermal system.

Equation (2) ensures the continuous balance between power demand and supply.

$$P_{\text{Grid}}^{\text{Import}}(t) + P_{Grid}^{Export\ \ PV}(t) + P_{Grid}^{Export\ \ CHP}(t) + P_{ElStorage}^{In}(t) + P_{ElStorage}^{Out}(t) + P_{PV}(t) + \ldots \\ P_{CHP}(t) + P_{Load}(t) = 0 \tag{2}$$

The feed-in of power from the photovoltaic system cannot exceed current generation (Equation (3)) nor the maximum feed-in limit (Equation (4)).

$$0 \geq P_{Grid}^{ExportPV}(t) \geq -P_{PV}(t) \tag{3}$$

$$-P_{PV}^{\max\ \ feed-in} \leq P_{Grid}^{ExportPV}(t) \leq 0 \tag{4}$$

In order to ensure that Equation (4) is followed at all times, the power considered of the photovoltaic system must be equal or smaller than current generation according to Equation (5). This can be ensured by a sub-optimal set-point in the solar controller.

$$0 \leq P_{PV}(t) \leq P_{PV}^{*}(t) \tag{5}$$

The cogeneration unit can be actively dispatched. To ensure that the generation remains within the operational limits, a binary decision variable *z(t)* is introduced, which reflects its current state (on/off). When the unit is operating, the output can be modulated within the bandwidth defined by Equations (6) and (7).

$$P_{CHP}(t) \geq z(t) \times P_{CHP}^{\min} \tag{6}$$

$$P_{CHP}(t) \leq z(t) \times P_{CHP}^{\max} \tag{7}$$

Equation (8) limits the feed-in from the cogeneration unit to the current generation.

$$0 \geq P_{Grid}^{ExportCHP}(t) \geq -P_{CHP}(t) \tag{8}$$

Last, the electric storage device is considered. Charge- and discharge power flows are limited according to the capacity rating of the storage device as indicated by Equations (9) and (10). Furthermore, in order to avoid simultaneous charge- and discharge operations, the binary variable $y(t)$ is introduced, which reflects the current operation mode ($y(t) = 1$ for charging, $y(t) = 0$ for discharging)

$$0 \leq P_{ElStorage}^{Out}(t) \leq P_{ElStorage}^{\max} \times (1 - y(t)) \tag{9}$$

$$-P_{ElStorage}^{\max} \times y(t) \leq P_{ElStorage}^{In}(t) \leq 0 \tag{10}$$

Based upon the power flows, the state of charge of the storage device can be calculated, considering the efficiencies of the operations $\eta_{ElStorage}^{In}$ and $\eta_{ElStorage}^{Out}$. The resulting state of charge is limited by the energy capacity and the minimum depth of discharge $\delta_{ElStorage}$, as indicated by Equations (11) and (12).

$$\sum_{n=1}^{t} P_{ElStorage}^{In}(n) \times \eta_{ElStorage}^{In} \times \Delta t + \sum_{n=1}^{t} P_{ElStorage}^{Out}(n) \times {}^{1}\!/\!\eta_{ElStorage}^{Out} \\ \times \Delta t \leq 0 \tag{11}$$

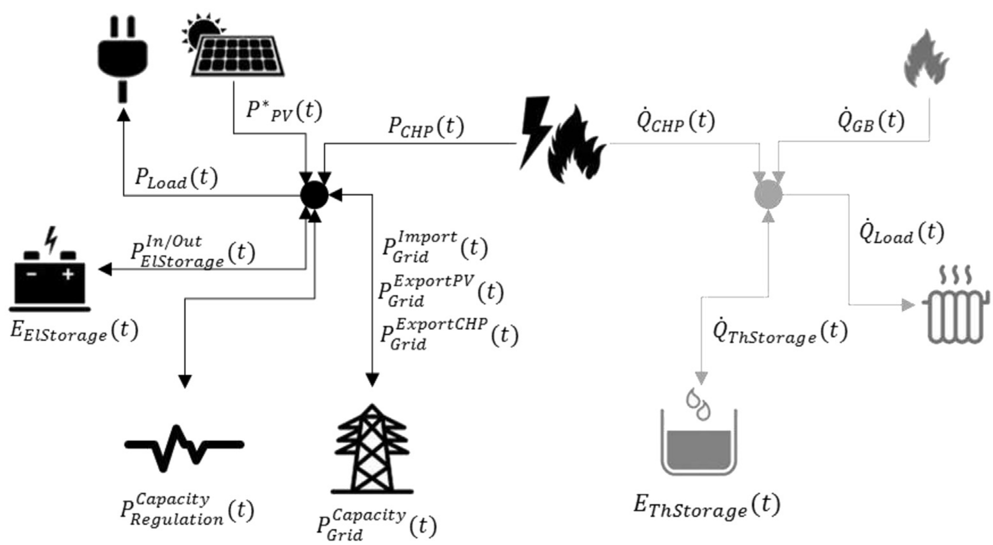

Fig. 1. Simplified representation of the system under analysis.

$$\sum_{n=1}^{t} P_{ElStorage}^{In}(n) \times \eta_{ElStorage}^{In} \times \Delta t + \sum_{n=1}^{t} P_{ElStorage}^{Out}(n) \times {}^{1}\!/_{\eta_{ElStorage}^{Out}} \times \Delta t \geq -E_{ElStorage}^{Capacity} \times \left(1 - \delta_{ElStorage}\right) \tag{12}$$

Following, the thermal system is considered. Analogous to Equations (2), (13) enforces that heat supply and demand are balanced in every time step.

$$\dot{Q}_{CHP}(t) + \dot{Q}_{GB}(t) + \dot{Q}_{ThStorage}(t) + \dot{Q}_{Load}(t) = 0 \tag{13}$$

The heat output of the cogeneration unit is defined by the chosen power generation, according to the constant ratio of the capacities as shown by Equation (14).

$$\dot{Q}_{CHP}(t) = P_{CHP}(t) \times \frac{\dot{Q}_{CHP}^{\max}}{P_{CHP}^{\max}} \tag{14}$$

The output of the gas burner is limited to its thermal rating (Equation (15)).

$$0 \leq \dot{Q}_{GB}(t) \leq \dot{Q}_{GB}^{\max} \tag{15}$$

Equation (16) limits the heat provided or absorbed to the rating of its heat exchanger.

$$-\dot{Q}_{ThStorage}^{\max} \leq \dot{Q}_{ThStorage}(t) \leq \dot{Q}_{ThStorage}^{\max} \tag{16}$$

Last, Equations (17) and (18) limit the state of charge of the thermal storage to its capacity, taking the self-discharge $\phi_{ThStorage}$ into account.

$$\sum_{n=1}^{t} \dot{Q}_{ThStorage}(n) \times \Delta t \times \left(1 - \Delta t \times \varphi_{ThStorage}\right)^{t-n} \leq 0 \tag{17}$$

$$\sum_{n=1}^{t} \dot{Q}_{ThStorage}(n) \times \Delta t \times \left(1 - \Delta t \times \varphi_{ThStorage}\right)^{t-n} \geq -E_{ThStorage}^{Capacity} \tag{18}$$

2.2. Provision of primary reserve control (PRC)

Besides time shifting of energy for later consumption, the storage device will simultaneously be dispatched to provide PRC. The storage power capacity, which is tendered for the provision of primary reserve control, is denominated $P_{\text{Regulation}}^{Capacity}(t)$ and must be constant during each tender period. The compensation of this service is given by $R^{Regulation}(t)$.

In order to consider the resulting revenues in the determination of the optimal dispatch, the objective function of the MILP (Equation (1)) has to be enlarged. Accordingly, the last term in Equation (19) reflects the additional income from the provision of PRC.

Additionally, Equation (20) ensures that the tendered power is constant during each tender period.

$$P_{\text{Regulation}}^{\text{Capacity}}(t) - P_{\text{Regulation}}^{\text{Capacity}}(t-1) = 0 \text{ for } t = 2, 3, \ldots \text{ of each tender period} \tag{20}$$

In addition, Equation (21) ensures that the tendered power capacity does not exceed the rating of the storage device.

$$0 \leq P_{\text{Regulation}}^{\text{Capacity}}(t) \leq P_{ElStorage}^{\max} \tag{21}$$

The resulting power $P_{Regulation}(t)$ must be considered in the balance of power, as indicated by Equation (22).

$$P_{\text{Grid}}^{\text{Import}}(t) + P_{Grid}^{Export\ \ PV}(t) + P_{Grid}^{Export\ \ CHP}(t) + P_{ElStorage}^{In}(t) + P_{ElStorage}^{Out}(t) + P_{PV}(t) + \ldots P_{CHP}(t) + P_{Load}(t) + P_{\text{Regulation}}(t) = 0 \tag{22}$$

As the dispatch of the storage for PRC is automatically activated by frequency deviations, sufficient spare power and energy capacity must be held available at all times. Hence, the available power to provide other services must be restricted. It is therefore no longer only limited by the capacity of the storage device (see Equations (9) and (10)), but also by the tendered capacity for PRC. Equation (23) implements the constraint for discharging operations, and Equation (24) for charging operations.

$$0 \leq P_{ElStorage}^{Out}(t) \leq \left(P_{ElStorage}^{\max} - P_{\text{Regulation}}^{\text{Capacity}}(t)\right) \times (1 - y(t)) \tag{23}$$

$$-\left(P_{ElStorage}^{\max} - P_{\text{Regulation}}^{\text{Capacity}}(t)\right) \times y(t) \leq P_{ElStorage}^{In}(t) \leq 0 \tag{24}$$

Besides reserving power for the provision of PRC, it must also be ensured that the state of charge remains within operational limits. Equation (25) (replacing (11)) ensures, that sufficient spare capacity is available to charge the storage device for 30 min, as required by German TSO's. Additionally, Equation (26) (replacing (12)) ensures that always sufficient energy is held available to provide energy for 30 min.

$$\sum_{n=1}^{t} P_{ElStorage}^{In}(n) \times \eta_{ElStorage}^{In} \times \Delta t + \sum_{n=1}^{t} P_{ElStorage}^{Out}(n) \times \eta_{ElStorage}^{Out\ \ -1} \times \Delta t \leq -P_{\text{Regulation}}^{\text{Capacity}}(t) \times 0.5h/_{\Delta t} \tag{25}$$

$$\max \Delta t \times \sum_{t=1}^{T} \begin{pmatrix} -P_{Grid}^{\text{Import}}(t) \times R_{Grid}^{\text{Import}}(t) - \dot{Q}_{GB}(t) \times C_{GB}^{Variable} - \left(P_{CHP}(t) + \dot{Q}_{CHP}(t)\right) \times C_{CHP}^{Variable} \ldots \\ -P_{Grid}^{Export\ \ PV}(t) \times R_{PV}^{Export}(t) - P_{Grid}^{Export\ \ CHP}(t) \times R_{CHP}^{Export}(t) \ldots \\ +P_{\text{Regulation}}^{\text{Capacity}}(t) \times R^{\text{Regulation}}(t) \end{pmatrix} \tag{19}$$

$$\sum_{n=1}^{t} P_{ElStorage}^{In}(n)\times\eta_{ElStorage}^{In}\times\Delta t+\sum_{n=1}^{t}P_{ElStorage}^{Out}(n)\times {\eta_{ElStorage}^{Out}}^{-1}\times\Delta t\geq -E_{ElStorage}^{Capacity}\times\left(1-\delta_{ElStorage}\right)+P_{\mathrm{Regulation}}^{\mathrm{Capacity}}(t)\times 0.5h/_{\Delta t} \tag{26}$$

Depending on the chosen simulation time step Δt, equations (25) and (26) simplify the problem slightly as they require the constant provision of capacity for 30 min, even if a control event occurred during the last period. This will result in a slightly sub-optimal dispatch.

2.3. Peak shaving (PS)

Last, the dispatch of the storage device will also take into account the cost for the required grid interconnection. The related fees are assumed to increase linearly with the contracted power $P_{Grid}^{Capacity}(t)$. In order to reduce the required grid capacity, the storage device will therefore be operated to provide power during local peak demand. Subsequently, during periods with lower demand, the storage device is then charged again.

In order to consider the cost in the dispatch, the objective function is enlarged once again leading to Equation (27) now including the capacity cost in its last term.

$$\max\Delta t\times\sum_{t=1}^{T}\left(\begin{array}{l} -P_{Grid}^{\mathrm{Import}}(t)\times R_{Grid}^{\mathrm{Import}}(t)-\dot{Q}_{GB}(t)\times C_{GB}^{Variable}-\left(P_{CHP}(t)+\dot{Q}_{CHP}(t)\right)\times C_{CHP}^{Variable}\ldots\\ -P_{Grid}^{Export\ \ PV}(t)\times R_{PV}^{Export}(t)-P_{Grid}^{Export\ \ CHP}(t)\times R_{CHP}^{Export}(t)\ldots\\ +P_{\mathrm{Regulation}}^{\mathrm{Capacity}}(t)\times R^{\mathrm{Regulation}}(t)\ldots\\ -P_{Grid}^{Capacity}(t)\times C_{Grid}^{Capacity}\end{array}\right) \tag{27}$$

Equation (28) ensures that the contracted power is constant during each billing period.

$$P_{\mathrm{Grid}}^{\mathrm{Capacity}}(t)-P_{\mathrm{Grid}}^{\mathrm{Capacity}}(t-1)=0\ \textit{for}\ t=2,3,\ldots\ \textit{of each power billing period} \tag{28}$$

Furthermore, once the contracted power is defined, it must be ensured that the power taken from the grid is less than the limit at all times, as indicated by Equation (29).

$$0\leq P_{\mathrm{Grid}}^{\mathrm{Import}}(t)\leq P_{Grid}^{Capacity}(t) \tag{29}$$

Feed-in of surplus generation will not be subject to this constraint. However, by limiting $P_{Grid}^{Export\ \ PV}(t)$ and $P_{Grid}^{Export\ \ CHP}(t)$ to the contracted capacity analogous to Equation (29), such a limitation can be easily implemented.

2.4. Implementation

For longer time horizons, it becomes computational very expensive to solve the above formulated MILP and – due to the resulting memory requirements – at some point this problem becomes no longer solvable. Therefore, the optimization horizon T will be split into shorter and better manageable periods. To ensure that the dispatch is still optimized across periods, an overlapping window connecting the individual periods will be considered in the MILP. Hence, the first optimization period will be from $t = 1 \ldots n + x$, where n is the duration of each optimization period in time steps and x is the duration of the overlapping period. However, after solving the problem, only the dispatch until n will be considered. Thereafter, the MILP for the period from $t = n + 1 \ldots 2n + x$ will be solved, and so on.

Fig. 2 shows that for very short optimization horizons n, the dispatch deviates significantly from the optimum. In this case, the shifting capability of the storage device cannot be fully utilized as the algorithm cannot look sufficiently far enough into the future and hence sub-optimal dispatch decisions would be obtained. However, considering an overlapping period x improves the result significantly.

Taking the computation time into account, an optimization horizon of 1 day with an overlapping period of at least 6 h offers a good trade-off between the complexity of the problem and quality of the results. Increasing the horizon or the overlapping period further only improves the dispatch marginally and at high computational cost.

Therefore, splitting the problem into smaller packets is a viable alternative in order to reduce the computational complexity. However, for the following analysis, it must be considered that each optimization period cannot be shorter than the tender period for the provision of PRC as well as the billing period for the contracted power.

3. - Results

The Case Study designed to illustrate the developed model and the adopted solution approach refers to a modern multi-family house located in Germany. All assumptions – except for the electrical storage device – are based on a real installation and representative for such a building [27].

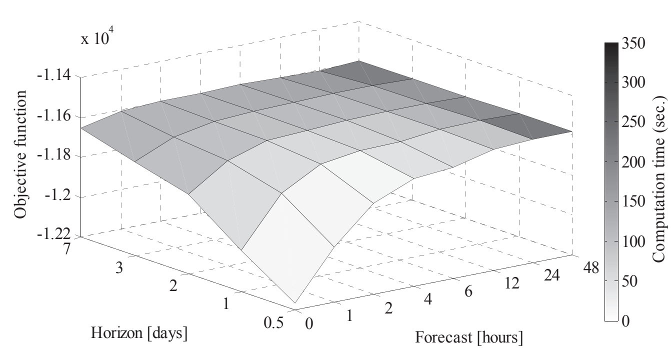

Fig. 2. Change of the objective function for different implementations of the MILP.

3.1. Assumptions

The annual thermal demand is assumed to be 220 MWh for heating and hot water and the annual electricity demand is 150 MWh. Both thermal as well as electricity demands are based on [28], which provides realistic time series with 15 min resolution.

3.2. The following system configuration is considered

- Photovoltaic system with $P_{PV}^{max} = 20kW$. Feed-in is compensated at $R_{PV}^{Export}(t) = 0,12€/kWh$ and cannot exceed $P_{PV}^{max\ \ feed-in} = 14kW$. Actual solar radiation data from the year 2005 [29] is scaled to the expected yield of 950 kWh/kW [30].
- Co-generation unit with $P_{CHP}^{max} = 16kW$ and $P_{CHP}^{min} = 5kW$. $\dot{Q}_{CHP}^{max} = 35,3kW$ and scales according to the chosen power output. Feed-in compensation is $R_{CHP}^{Export}(t) = 0,035€/kWh$. The operating cost $C_{CHP}^{Variable}$ is assumed to be 0,05 EUR/kWh.
- A gas boiler to meet peak heat demand with $\dot{Q}_{GB}^{max} = 100kW$ and $C_{GB}^{Variable} = 0,05€/kWh$.
- Electrical storage device with $E_{ElStorage}^{Capacity} = 50kWh$, $P_{ElStorage}^{max} = 20kW$, $\delta_{ElStorage} = 25\%$ and $\eta_{ElStorage}^{In}$ / $\eta_{ElStorage}^{Out} = 95\%$. Self-discharge is assumed to be 0.
- Thermal storage device with $E_{ThStorage}^{Capacity} = 100kWh$ and $\dot{Q}_{ThStorage}^{max} = 50kW$. Hourly self-discharge amounts to $\phi_{ThStorage} = 0{,}35\%$, there are no efficiency losses or minimum depth of discharge.

To consider the impact of having different generation and demand values, the simulations were conducted for a full year.

Regarding the electricity tariffs, two tariff schemes are considered:

- Tariff 1 with an energy charge of $R_{Grid}^{Import}(t) = 0,265€/kWh$.
- Tariff 2 with an energy charge of $R_{Grid}^{Import}(t) = 0,238€/kWh$ and a weekly demand charge ($C_{Grid}^{Capacity}$) of 2,52€/kw. The demand charge is set according to the highest average power demand over each 15-minute period during each week.

The compensation for the provision of ancillary services ($R^{Regulation}(t)$) is assumed to be 2€/kW and week. The tender period is assumed to be weekly and we assumed there are no constraints regarding the bid size. However, while the previously presented model ensures that sufficient energy and power capacity is reserved at all times, no control events will be considered in the simulation. Instead, it is implicitly assumed that the storage device makes use of a recent regulation change and is charged-/discharged within the frequency dead-band in order to return to the required state of charge.

3.3. Reference Case

As a reference, the annual energy cost without the presence of any storage device amounts to 27243 EUR when considering Tariff 1 and 30085 EUR under Tariff 2 given the above presented system configuration. While the cost for electricity taken from the grid decreases by 1230 EUR under Tariff 2, the saving is more than offset by the additional demand charge of 4072 EUR. The dispatch differs slightly between both tariff schemes, as the cogeneration unit is now operated in such a way to also reduce peak demand. Thereby, the average required grid capacity along the year decreases from 36,9 kW under Tariff 1–31 kW under Tariff 2.

For consumers with significant local generation, a switch to a tariff with a demand charge appears economically uninteresting as the additional fee cannot be offset by the savings from the lower energy price. In the following, all dispatches considering the operation of the storage device for peak shaving will be compared to the Reference Case under Tariff 2. All other dispatches will refer to Tariff 1.

3.4. Individual value

Following, the value added from each individual application will be estimated. Therefore, the MILP must be adapted to segregate each of the value streams.

In order to exclude the value contribution from Peak Shaving or provision of PRC on Time Shifting operations, the respective cost and revenue are set to zero. The dispatch results in an annual cost reduction of 1407 EUR versus the Reference Case under Tariff 1.

To segregate the value for providing Primary Reserve Control, the power capacity of the storage device was completely reserved for only this purpose. The dispatch was found to be slightly more rewarding than just pursuing Time Shifting, with a benefit of 2102 EUR versus the Reference Case.

The value of Peak Shaving is estimated considering Tariff 2, which is a prerequisite for dispatching the storage device for this application due to the demand charges. However, the identification of the benefit is more complex due to the interaction of Time Shifting with Peak Shaving. The feed-in tariffs were set marginally below R_{Grid}^{Import} in order to prevent time-shifting operations, as feeding surplus generation into the grid and taking it back at a later point in time becomes more favourable due to the avoided efficiency losses from the storage process. However, immediate self-consumption of local generated electricity is still favoured due to the minimal benefit versus the regular Tariff. In addition, $R^{Regulation}$ is set to zero to exclude the provision of reserve control. Solving the

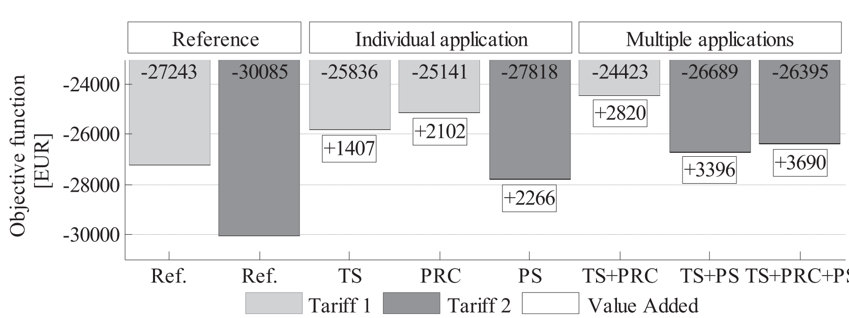

Fig. 3. Comparison of applications and their value added.

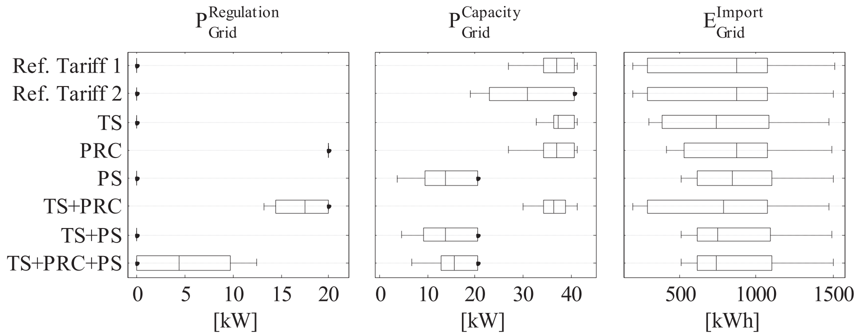

Fig. 4. Comparison of dispatch across settings.

MILP showed that the required grid capacity was significantly reduced, on average from 31 kW to only 13,7 kW, resulting in a benefit of 2266 EUR compared to the Reference Case under Tariff 2.

Fig. 3 compares the value added by the individual applications regarding the Reference Case. Time shifting as well as providing reserve control clearly generate value. While peak shaving was shown to be profitable, the benefit is not sufficient to justify a switch from Tariff 1 to the more expensive Tariff 2. In this case, the additional cost due to the more expensive tariff still outweighs the storage benefits.

3.5. Combined value

After determining the benefit of storage when it is dispatched for each individual application, it will be analyzed if the value added by storage can be further increased if the device is dispatched simultaneously for multiple purposes.

To determine the benefit from time shifting and providing reserve control simultaneously, $C_{Grid}^{Capacity}$ is assumed to be zero in the MILP. The optimal dispatch results in an improvement of the objective function of 2820 EUR under Tariff 1 when compared with the Reference Case.

Contrary, by setting $R^{\text{Regulation}}$ to zero to exclude the value generation from PRC, the value of time shifting and peak shaving in parallel can be estimated. The benefit versus the Reference Case under Tariff 2 amounts to 3396 EUR.

Last, the initially presented MILP is solved without any further modification to determine the value of providing all three services simultaneously. The benefit increases further to 3690 EUR versus the Reference Case under Tariff 2.

Hence, stacking multiple applications is indeed able to further improve the value proposition of storage. However, comparing the benefit from the combined dispatch to the individual benefits also shows that the result is not a linear combination of the individual values, but that storage operations interfere. Slightly less than 80% of the theoretical value from the individual applications can be obtained, when dispatching the storage device for two applications. The revenue gap further increases when all three applications are simultaneously pursued. In this case, only about 64% of the theoretical revenue resulting from the addition of individual values can be obtained.

Fig. 4 compares the required grid capacity, the tendered capacity for reserve control as well as the amount of energy taken from the grid across the different settings. The boxes represent the 25th/75th percentile of the weekly data along the year, with the whiskers extending to about 99% of all data. The centre line reflects the mean.

When PRC is provided individually, all power capacity of the storage device is constantly tendered. However, when providing it in combination with at least one of the other two services, the tendered capacity fluctuates and is generally lower. Hence, the storage device regarding the provision of reserve control is dispatched depending on the availability of local generation and opportunities for peak shaving.

The required grid capacity varies significantly across the different settings. When no demand charge is made, the required grid capacity remains unchanged. Contrary, the maximum power demand is reduced to less than half the original value. Notably, given the assumed tariffs, pursuing time shifting in parallel to peak shaving obviously can be accommodated well in the dispatch process, as it has very little impact on the resulting grid capacity requirements.

The third column of Fig. 4 compares the amount of energy taken from the grid. With the storage device pursuing time shifting, the average amount is significantly reduced. However, apparently, the demand remains unchanged during many weeks.

Fig. 5 compares the reduction in the required grid capacity, the provision of reserve control as well as the amount of shifted energy along the year for the dispatch, when all services are pursued simultaneously. The data shows a strong seasonal variation.

During the winter months, the amount of energy shifted in time is larger, driven by the generation of the CHP unit. During the summer, significantly less surplus generation is available, resulting

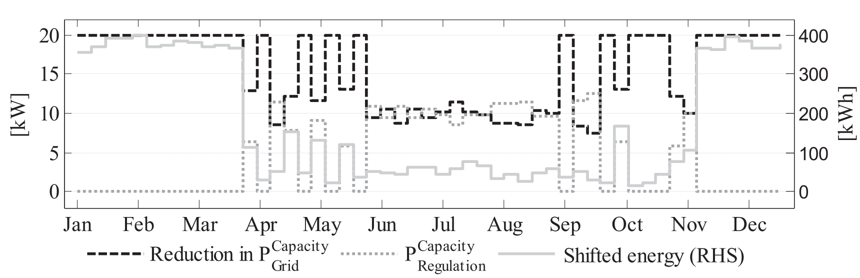

Fig. 5. Storage dispatch along the year.

in less energy shifted in time. Analogous, the reduction in grid capacity is also lower during the summer. However, as less storage capacity is used for time shifting and peak shaving, more power can be tendered for reserve control. Hence, the provided capacity for PRC is highest during the summer.

While the analysis showed that storage can generate significant benefits and cost reductions, a more complete evaluation obviously also needs to take investment cost into account. Assuming an investment cost of 36000 EUR and a calendric lifetime of 12 years results in an annual depreciation charge of 3000 EUR. Given the savings of deploying storage as shown in Fig. 3, it becomes obvious that electrical storage cannot yet be deployed profitably for an individual service under the assumed framework. However, if storage is dispatched for several applications simultaneously, an investment can be interesting under today's cost.

In a more complete financial evaluation, it should be taken into account that the lifetime of most battery based storage systems is also affected by their operation. A dispatch co-integrating several applications results in a more frequent usage of the storage device, which might degrade battery based storage devices prematurely due to the much higher numbers of cycles. Exemplary, co-integrating time shifting and peak shaving results in 288 storage cycles during the considered period of one year, whereas under the individual dispatch approaches only 203/158 cycles are required.

The previous analysis confirms the economic benefit of storage to shift surplus generation in time, which was previously identified by ([2,3,8]). Due to the high share of grid-related cost, the application in the German case is especially attractive. With regards to peak-shaving and the provision of primary reserve control, the values we obtained are in line with previous research ([12,13,15,16]). The benefit of aggregating multiple applications, which was previously shown for the applications of arbitrage and the provision of ancillary services on a grid-level ([21–25]), also exists in a consumer setting. In this context, it was shown that time-shifting, peak-shaving and the provision of primary reserve control can be combined yielding important advantages to local consumers.

4. - Conclusions

In this work, a Mixed Integer Linear Program was developed which minimizes the energy supply cost of a residential consumer by optimally dispatching local generation resources and storage considering multiple applications as a way to enlarge the revenues. In order to correctly integrate the simultaneous heat and power output of the cogeneration unit, the model considers in addition to the electrical system also the thermal system.

It was shown that electrical storage can reduce energy cost by increasing the self-consumption of locally generated energy or by reducing demand charges. Furthermore, additional income can be generated by using the storage device for the provision of primary reserve control. By dispatching the device for multiple applications simultaneously, the benefit can be further increased, even though the operations restrict each other and hence the revenues are not additive thus originating a revenue gap.

Overall, given the high investment cost, storage was found to be not yet profitable if dispatched for only one application. However, dispatching it for multiple services simultaneously allows the storage investment to achieve the break-even point. Switching to a tariff with demand charges to purse peak shaving was found to be economically uninteresting. However, consumers which already have to pay a demand charge can significantly reduce this cost by dispatching the storage device for this purpose.

The dispatch was found to vary considerably along the year, driven by the availability of generation from the cogeneration unit and the photovoltaic system. The resulting operation of the storage device is opportunistic, highlighting the benefit of dispatching the storage device for several applications simultaneously.

While storage was shown to reduce the energy cost at the consumer site, it is clear that the quality of the final results depends on the accuracy of the input data, namely regarding the demand and solar radiation. Especially the dispatch for peak shaving depends on an accurate identification of peak demand. Although the dispatch process can always be conducted using forecasted values, further research should be directed to develop an operational dispatch process that is less sensitive to the quality of forecasts. Furthermore, the presented work assumes a given system configuration. Most likely, the value of storage can be further improved by optimizing the system configuration and the capacities. Last, regulatory barriers and requirements, which for example tightly control the provision of reserve control, still present a complex implementation hurdle.

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